STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 97-596

February 29, 2000

PUBLIC UTILITIES COMMISSION
Investigation of Stranded Cost Recovery, Transmission and Distribution Utility Revenue Requirements, and Rate Design of Bangor Hydro-Electric Company (Phase II)

ORDER

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

I. SUMMARY

By way of this Order, we approve a Revised Stipulation which sets rates for Bangor Hydro-Electric Company (BHE or the Company), effective March 1, 2000, the start of retail competition for generation services in Maine. Under the terms of this Order, assuming all customers take standard offer service, the average total rate for electricity for BHE customers will decrease by 2.4% when compared to today's bundled rates.

II. BACKGROUND

On November 24, 1999, we issued our decision in Phase I of this proceeding. In that Order, we established the principles and methodologies by which we would set BHE's stranded costs, T&D revenue requirements and rates for service beginning March 1, 2000. We also resolved most of the standard revenue requirement issues and established BHE's overall pre-tax cost of capital at 12.37%, based on a cost of equity of 11.0%. We did not attempt to establish a final overall stranded cost number since the results of the Company's Qualifying Facility Contract entitlement auction were not yet known and standard offer prices had not yet been set. The Company was directed to submit a Phase II filing in order to address these matters and certain other limited issues which either we had identified as needing updating in Phase I or which the Company believed required updating.

On December 17, 1999, BHE submitted its Phase II filing. On January 14, 2000, the litigation schedule which had previously been established was suspended to allow the parties an opportunity to resolve these matters informally. The Company submitted an updated Phase II filing on January 19, 2000. A series of settlement conferences were held during January and February. On February 9, 2000, the Company and the Office of the Public Advocate submitted a Stipulation which resolved all Phase II issues. The Industrial Energy Consumers Group (IECG) opposed the Stipulation. A hearing was held on the IECG's objections on February 11, 2000. For the reasons set forth below, during our deliberations on February 11, 2000, we rejected the Stipulation (referred to as the "Initial Stipulation"). The Company and the OPA submitted a Revised

Stipulation, on February 18, 2000 which was intended to address the issues raised by our rejection of the Initial Stipulation.

III. THE INITIAL STIPULATION

A. Description of the Stipulation

The parties to the February 9, 2000 Stipulation agreed to a $104,454,730 total revenue requirement. This overall revenue requirement was comprised of a T&D revenue requirement of $63,314,466, a stranded cost revenue requirement of $40,864,020 and an attrition adjustment of $276,244. The stranded cost revenue requirement was based on a 5-year uneven amortization of the Company's Asset Sale Gain Account (ASGA) which was intended to minimize fluctuations in stranded costs and ultimately rates over the 5-year period.

To implement the top-down rate design methodology adopted in our Phase I Order, the parties agreed to use back-out generation costs of $0.45/kWh, the standard offer rate proposed by the Company in its January 20, 2000 filing for the Company's small (residential, general service and commercial) and medium (D-1 and D-2) classes; $.043/Wh for the D-4 class and $.041/kWh for the D-5 class. If the Commission established initial standard offer rates greater than those proposed by BHE for the small and medium classes, the increased standard offer prices would be used to implement the top-down approach. In addition, for each .01¢/kWh increase in the standard offer price for the small and medium classes the amortization of the ASGA would be increased during the period of March 1, 2000 through February 28, 2002, by an amount sufficient to reduce annual revenue requirements by $100,000 per year. These reductions would be applied solely to core T&D rates for customers in the small and medium standard offer classes. The parties to the Initial Stipulation recognized that accelerating the amortization of the ASGA could increase revenue requirements in future years which could be mitigated by altering the amortization of other regulatory assets, including the Ultrapower amortization. If the Ultrapower regulatory asset amortization is subsequently modified the "Ultrapower adjustment" adopted by the Commission in Docket No. 95-109 would be calculated in a manner that holds BHE's investors from any extension of the amortization of the Ultrapower amortization schedule.

The parties to the Initial Stipulation also agreed that certain costs and revenues could not be determined with reasonable certainty at this time and therefore, to the extent such costs or revenues were not reflected in revenue requirements as agreed to in this case, they should be deferred for future recovery in rates. Specifically, the parties agreed for special ratemaking treatment for the following costs and revenues:

1) Interim Savings from the Asset Sale. Actual replacement power costs through February 29, 2000 included in the calculation of the Interim Savings from the Asset Sale.

2) Chapter 380 DSM Expenses. DSM assessments and expenses incurred as a result of the State Planning Office recommendation pursuant to 5 M.R.S.A. § 3305-B.

3) Standard Offer. Any over- or under-collection of costs related to the provision of standard offer service according to the terms of Docket No. 99-111.

4) Graham Station Units 4 and 5. The actual costs and revenues associated with the pending sale of Graham Station Units 4 and 5.

5) PERC Warrants. The costs associated with the exercise of rights under the PERC stock warrants made after January 20, 2000.

6) Restructuring. The actual extraordinary expenses that were incurred in preparing for restructuring as authorized in the Commission's September 8, 1999 Accounting Order in this proceeding.

7) Unbundled Special Rate Contracts. The difference between T&D rates estimated in calculating revenue requirements and actual T&D rates charged for contracts which are required to be unbundled pursuant to 35-A M.R.S.A. § 3224(10) and for bundled contracts which expire prior to the start of restructuring and are extended as T&D only contracts.

8) Gains on the Sales of Gas Pipeline Easements. The revenue received by BHE from the sale of natural gas pipeline easements to the extent similar revenue received by CMP has been deferred for ratemaking.

B. Opposition to the Stipulation

The Initial Stipulation was opposed by the IECG. At the hearing on the Initial Stipulation, Dr. Richard Silkman, on behalf of the IECG, testified that the standard offer rates used in the Initial Stipulation's top-down rate design methodology were too low given what he had seen in the marketplace. The artificially low standard offer prices posed several risks. First, it created the risk that those customers who did shop would be "losers" since they could not get such rates in the market. Dr. Silkman also expressed concern that the Company would undercollect standard offer revenues and thus customers who took the risk and chose to shop for generation services in the market would essentially have to pay twice; once in the market and again when standard offer revenues were reconciled.

C. Decision on the Initial Stipulation

As a general matter we believe that the Initial Stipulation reasonably resolved the issues in the case. The Company did not introduce any major new revenue requirement issues in its revised Phase II filing. Thus, the major issues to be

resolved in Phase II were the amortization of the ASGA and the implementation of the top-down rate design methodology. The parties in the Initial Stipulation agreed to an uneven amortization of the ASGA over five years in a manner which would levelize stranded costs over that period. We believe this approach reasonably allocates the benefits of the Company's asset sales to its customers while minimizing rate fluctuations over the next several years.

The Initial Stipulation implemented the top-down methodology adopted by the Commission in Phase I by allocating the total reduction from BHE's current bundled revenues to the new T&D revenue requirement to BHE's customer classes in proportion to each class's expected total generation service obligation. Generation service costs for the small and medium customer classes were calculated by using the proposed standard offer rates of 4.5¢/kWh for such classes. We find this overall methodology to be reasonable.

For the reasons set forth in our Order in Docket No. 99-111 being issued today, we have set the standard offer rates for BHE's medium (D-1 and D-2) class customers at 4.9¢/kWh. We agree with the provisions of the Initial Stipulation which would mitigate adverse bill impacts for these customers by accelerating the ASGA amortization and target such revenue requirement reductions to the affected classes. Since we have, in Docket No. 99-111, increased the standard offer rate for medium class customers but not for small class customers, and since the Initial Stipulation anticipated that both classes would either be increased or not increased and only provides for a revenue requirement reduction if we increase both classes, we must reject the Initial Stipulation as proposed. At our February 11, 2000 deliberative session, we found that all other aspects of the Initial Stipulation were reasonable, and thus, we would accept a stipulation revised to address the bill impact issues to the D-1 and D-2 classes.

IV. THE REVISED STIPULATION

A. Description of the Revised Stipulation

The Company and the OPA submitted a Revised Stipulation in response to our decision, set forth above, to reject the Initial Stipulation. Other than as noted below, the Revised Stipulation follows the language and methodologies of the Initial Stipulation.

The Revised Stipulation uses the same generation rates to implement the top-down methodology used in the Initial Stipulation. To offset the increase in the standard offer rates for D-1 and D-2 customers from 4.5¢/kWh to 4.9¢/kWh, however, the revenue requirements of these two classes were reduced, by $1,033,002 for the D-1 class and $241,876 for the D-2 class. These reductions were achieved by accelerating the amortization of ASGA. The parties to the Revised Stipulation agree that as a result of the reduction to T&D rates of the D-1 and D-2 rate classes achieved through amortizing additional amounts of available value from the ASGA, that in a future rate

proceeding the relative rates of these classes may be modified to reflect a reduced amount of available value to ensure that all classes receive a reasonable share of such available value. Under the provisions of the Revised Stipulation, the Company may restrict the D-1 and D-2 classes to those customers with applicable demands of 500 kW, unless such customers were members of these classes on or before February 18, 2000.

The Initial Stipulation did not calculate a rate for the Company's D-3 class, which currently does not have any customers. The Revised Stipulation provides that the D-3 T&D-only rate shall be calculated by reducing the current D-3 bundled energy rate by the same percentage used to reduce the current bundled energy charges for the D-4 class.

As a result of the increased amortization of the ASGA to achieve the D-1 and D-2 class revenue requirement reductions, the Company's overall revenue requirement agreed to in the Revised Stipulation was reduced to $103,178,972.

B. Opposition to the Revised Stipulation

The IECG was not a party to the Revised Stipulation. In a letter to the Commission dated February 22, 2000, counsel for the IECG indicated that the IECG supported the Revised Stipulation with three exceptions. First, the IECG urges that the following language should be added to the language which provides for the possible modification of rates to customers in the D-1 and D-2 classes:

> [a]ny such modification must take into consideration the amount of any deferrals that result from the non-final nature of the BHE standard offer prices for all customers.

Second, the IECG argues that BHE should not be allowed to recover the restructuring expenses authorized for deferral by our September 8, 1999, Accounting Order in this proceeding unless BHE enrolls customers who make a competitive choice in a timely manner. Finally, the IECG suggests the term "recovery" as used in the Accounting Order section of the Revised Stipulation be replaced by the term "reconciliation," as the actual computations may involve positive or negative numbers.

C. Decision

In past cases, we have applied the following criteria when considering stipulations:

1. whether the parties joining the Stipulation represent a sufficiently broad spectrum of interests that the Commission can be sure that there is no appearance or reality of disenfranchisement;

2. whether the process that led to the Stipulation was fair to all parties; and

3. whether the stipulated result is reasonable and is not contrary to legislative mandate.

See Central Maine Power Company, Proposed Increase in Rates, Docket No. 92-345(II), Detailed Opinion and Subsidiary Findings (Me. P.U.C. Jan. 10, 1995), and *Maine Public Service Company, Proposed Increase in Rates (Rate Design)*, Docket No. 95-052, Order (Me. P.U.C. June 26, 1996). We have also recognized that we have an obligation to ensure that the overall stipulated result is in the public interest. *See Northern Utilities, Inc., Proposed Environmental Response Cost Recovery*, Docket No. 96-678, Order Approving Stipulation (Me. P.U.C. April 28, 1997). We find that the Revised Stipulation in this case meets all of the above criteria.

As discussed in Section III(C), *infra*, we found that the provisions of the Initial Stipulation were reasonable, but the Stipulation should be modified to reflect our decision to increase standard offer rates to the D-1 and D-2 classes. By targeting an additional revenue requirement reduction of $1,033,002 for the D-1 class and $241,876 for the D-2 class to offset the increases in the standard offer rates which were ordered in our decision in Docket No. 99-111, the Revised Stipulation has properly addressed the issues raised by our decision to reject the Initial Stipulation. For the reasons set forth below, we do not find that the issues raised by the IECG provide a basis for rejecting the Revised Stipulation.

With regards to the IECG's first exception, the language concerning future rate changes for the D-1 and D-2 classes which the IECG proposes be modified does not direct any particular outcome but merely suggests a position that the Company and the OPA might take. The IECG, as well as any other party, will be free to raise the issue of standard offer deferral as well as any other rate design issue it believes to be appropriate at such time.

With regards to the IECG's proposed change concerning deferred restructuring expenses, we will review the prudence of such costs in the near future, pursuant to the terms of our September 8, 1999 Accounting Order which authorized BHE to defer certain restructuring costs for recovery in rates. If BHE fails to enroll customers who make a timely choice of a competitive electricity provider subsequent to the start of retail access, such conduct will be looked at in the context of our overall prudence review of the Company's costs. We do not believe that any prior finding of imprudence, as requested by the IECG, should be made at this time.

We do agree with the IECG that the term "recovery" should apply in a manner that both the Company and its ratepayers may benefit. We believe the Revised Stipulation contemplates both reductions and recoveries based on increased or decreased revenues and costs. In a letter dated February 22, 2000, the Company confirms this fact and we have reflected this clarification below in the ordering paragraph authorizing the deferrals.

The Revised Stipulation has been signed by the Company and the OPA. The Revised Stipulation has also been supported, with the exceptions noted above, by the IECG. The Revised Stipulation was also filed after hearings were held in Phase I of the case and on the Initial Stipulation and on Phase II. There has been no suggestion that settlement talks were conducted in a manner that was anything but fair. We are thus satisfied that there has been no disenfranchisement through our approval of the Revised Stipulation; that the process that led up to the Revised Stipulation was fair and that the overall stipulated result of the Revised Stipulation is in the public interest.

Accordingly, it is

O R D E R E D

1. That the February 9, 2000 Initial Stipulation filed in this proceeding is rejected.

2. That the Revised Stipulation filed on February 18, 2000 is approved. A copy of the Revised Stipulation is attached hereto as Appendix A and is incorporated by reference.

3. That the Company shall file rate schedules to take effect March 1, 2000 designed to collect revenues of $103,178,972 and otherwise in accordance with the terms of this Order.

4. That the Accounting Orders proposed in paragraph 6 of the Revised Stipulation authorizing deferral of certain costs and revenues for future recovery or reductions in rates are granted.

Dated at Augusta, Maine, this 29th day of February, 2000.

BY ORDER OF THE COMMISSION

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Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Diamond

THIS DOCUMENT HAS BEEN DESIGNATED FOR PUBLICATION

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 30 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Civil Procedure, Rule 73, et seq.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

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